BEFORE THE

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

IN RE:	)	
Application of South Carolina Electric & Gas Company for Adjustments in the Company's Electric Rate Schedules and Tariffs and Request for Mid-Period Reduction in Base Rates for Fuel	)	**DOCKET NO. 2012-218-E**

Direct Testimony and Exhibits of

Nicholas Phillips, Jr.

On behalf of

Federal Executive Agencies

October 26, 2012

BRUBAKER & ASSOCIATES, INC.

Project 9651

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<u>Direct Testimony of Nicholas Phillips, Jr.</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and managing principal with the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants. I have testified in many electric and gas rate proceedings on virtually all aspects of ratemaking. More details are provided in Appendix A of this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am appearing on behalf of the Federal Executive Agencies. Our firm is under contract with The United States Department of the Navy to perform cost of service, rate design and related studies. The Department of the Navy represents the

Department of Defense and all other Federal Executive Agencies ("FEA") in this proceeding.

Q HAVE YOU PRESENTED TESTIMONY IN PRIOR PROCEEDINGS BEFORE THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION ("COMMISSION" OR "SCPSC")?

A Yes. I have been involved in many prior proceedings before this Commission concerning South Carolina Electric and Gas ("SCE&G"), as well as other utilities.

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A I am presenting testimony concerning the appropriate cost allocation methodology for use in this proceeding, the revenue distribution to classes of any amount of rate increase granted by the Commission, and the proper design of SCE&G's electric rates. There are certain general principles that should form the basis for cost allocation, revenue distribution, and rate design. I have examined the testimony and exhibits presented by SCE&G in this proceeding with respect to cost allocation and rate design, I will comment upon the propriety of these proposals and make certain recommendations.

Q DOES YOUR TESTIMONY ADDRESS SCE&G'S NEED FOR AN INCREASE IN ELECTRIC RATES?

A No. In order to make my presentation consistent with the revenue levels requested by SCE&G, I have, in many instances, used their numbers for rate base, operating income, and rate of return. Use of these numbers should not be interpreted as an endorsement of them for purposes of determining the total dollar amount of rate increase to which SCE&G may be entitled. SCE&G is requesting a $151.5 million base (non-fuel) rate increase in this proceeding. The $151.5 million requested base rate increase is a 6.61% increase to total revenues and a 10.0% to base (non-fuel) revenues. SCE&G proposes to reduce fuel charges because fuel costs are declining. However, fuel cost recovery is an annual event based on a dollar-for-dollar recovery of prudent fuel costs and is not the same as the requested $151.5 million base rate increase which remains in effect until another base rate increase is filed. Stated in another matter, reduced fuel costs would flow through to ratepayers absent this requested increase. I recommend the appropriate distribution to classes of any amount of rate increase allowed by the Commission.

Summary of Conclusions and Recommendations

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING.

A A summary of my position and recommendations is listed below:

1. The SCE&G filing in some instances emphasizes the net impact of the requested base rate increase and its proposed fuel decrease. However, the $151.5 million base rate increase remains in effect while the fuel decrease is a one-year event subject to true-up and carrying charges for under-recovered amounts. It is inappropriate to consider the two together unless both are constant.

2. SCE&G's electric rates should be based on the cost of providing service to each customer class.

3. Having analyzed SCE&G's summer peak, winter peak, and load pattern, I conclude that the summer peak responsibility cost of service study is appropriate for use in this proceeding. It properly allocates cost responsibility to customer classes and, if implemented properly, minimizes the need for new generating capacity consistent with SCE&G's load management goals.

4. SCE&G's proposed distribution of its requested rate increase is based on cost of service and does move all rate classes toward the system average rate of return. However, current circumstances including the weak economic recovery, and the possible impact of the recession on load patterns call for a more measured movement toward cost of service at this time.

5. For this case, in this fragile period, it is appropriate to maintain existing rate relationships. The most appropriate and recognized manner to achieve this goal is to increase existing non-fuel revenue levels for each class by the same uniform percentage of overall increase authorized as shown on Schedule 3 of Exhibit NP-2.

<u>Cost of Service and Rate Design Principles</u>

Q PLEASE EXPLAIN THE BASIS FOR YOUR EVALUATION AND DESIGN OF RATES.

A The ratemaking process has three steps. First, the determination of the utility's total revenue requirement and whether an increase in revenues is necessary. Second, we must determine how any increase in revenues is to be distributed among the various customer classes. A determination of how many dollars of revenue should be produced by each class is essential for obtaining the appropriate level of rates. Finally, individual tariffs must be designed to produce the required amount of revenues for each class of service and to reflect the cost of serving customers within the class.

The guiding principle at each step should be cost of service. In the first step – determining revenue requirements – it is universally agreed that the utility is entitled to an increase only to the extent that its actual cost of service has increased. If current rate levels exceed revenue requirement, a rate reduction is required. In short, rate revenues should equal actual cost of service. The same principle should apply in the second two steps. Each customer class should, to the extent practicable, produce revenues equal to the cost of serving that particular class, no more and no less. This may require a rate increase for some classes and a rate decrease for other classes. The standard tool for determining this is a class cost of service study that shows the rates of return on each class of service. Rate levels should be modified so that each class of service provides approximately the same rate of return. Finally, in designing individual tariffs, the goal should also be to relate the rate design to the cost of service so that each customer's rate equals, to the extent practicable, the utility's cost of providing that service.

Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATE DESIGN PROCESS?

A The basic reasons for using cost of service as the primary factor in the rate design process are equity, engineering efficiency (cost minimization), conservation, and stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A When rates are based on cost, each customer (to the extent practical) pays what it costs the utility to provide service to that customer, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenues by subsidizing service provided to other customers. This is inherently inequitable.

Q HOW DO COST-BASED RATES ACHIEVE THE ENGINEERING EFFICIENCY (COST MINIMIZATION) OBJECTIVE?

A Cost minimization is achieved when customers receive the appropriate price signals through the rates that they pay. Rate design is the step that follows the allocation of costs to classes, it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand, and customer components of the rate schedules, respectively, customers are provided with the proper incentives to minimize their costs, which will in turn minimize the costs to the utility.

From a rate design perspective, over-pricing the energy portion of the rate and under-pricing the fixed components of the rate (such as customer and demand charges) will result in a disproportionate share of revenues being collected from high load factor customers.

Q PLEASE GIVE AN EXAMPLE.

A I will focus upon the two components of the rates applicable to large customers that are predominant in terms of cost causation and revenue collection. These are the demand component and the energy component.

Assume that a given dollar amount of revenue is to be collected from application of these two elements. From a rate design perspective, various combinations of revenue collections from the demand and energy charge are, of course, possible. These possibilities range from the collection of all such costs through an energy charge, with no collection through the demand charge, to the collection of all such costs through a demand charge, with no collection through the energy charge. Obviously, neither of these extreme possibilities reflect reasonable rate design since there are definite demand and energy components to the cost of serving customers.

In between these two extremes, there is a range of possibilities. The most obvious possibility is to base the demand charges on the demand costs and the energy charges on the energy costs. To the extent that there is an overall correspondence between costs and revenues to be collected, basing the demand charge on the demand cost and the energy charge on the energy cost will most closely charge each customer with the appropriate revenue responsibility.

To illustrate the cost minimization concept, assume that a cost-based rate would contain a $15 per kilowatt (kW) demand charge and a 2¢ per kilowatthour (kWh) energy charge. Suppose, however, that an alternate rate was instead designed with a $3.00 per kW demand charge and a 5¢ per kWh energy charge. (It is implicit that application of both of these rates to the total class test year billing determinants would produce the same total revenue.)

Consider the effect of the alternate rate as compared to the cost-based rate. When a customer faces a demand charge of $3 per kW, the price signal he gets is that imposition of peak demands on the utility's system is not very costly. Thus, there is less incentive to control peak loads with a below-cost demand charge than if the customer faces a demand charge that more nearly approximates demand costs. To the extent that the customer reacts to this below-cost demand charge, the tendency will be for system peak loads to be higher than otherwise, which will impose additional costs on the utility – costs that may have to be collected from all customers.

Consider now the effect of charging an energy rate of 5¢ per kWh, as compared to an energy cost of 2¢ per kWh. The customer is influenced to use less energy than would be the case if the rates were cost-based. This will tend to increase customer preferences for alternate energy supplies, and particularly so for high load factor customers who use a large amount of energy in relation to their peak load. This problem becomes particularly exacerbated if significant overcharges occur during the low load (off-peak) periods on the utility's system, when additional energy consumption at lower rates would be beneficial to the system.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful or inefficient uses are discouraged or minimized. Only when rates are based on actual costs do customers receive a balanced price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted signals. It is important that the costs associated with certain conservation and demand management programs should not create a new form of subsidization and move rates away from cost.

Q PLEASE DISCUSS THE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the earnings impact on the utility of changes in customer use patterns will be minimized as a result of rates being designed in the first instance to track changes in the level of costs. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need for filings for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of power costs. If rates are based on factors other than costs, it becomes much more difficult for customers to translate expected utility-wide cost changes (i.e., expected increases in overall revenue requirements) into changes in the rates charged to particular customer classes (and to customers within the class). This situation reduces the attractiveness of expansion, as well as of continued operations, because of the lessened ability to plan.

Q WHEN YOU SAY "COST," TO WHAT TYPE OF COST ARE YOU REFERRING?

A I am referring to the utility's "embedded" or actual accounting costs of rendering services; that is, those costs that are used by the Commission in establishing SCE&G's overall revenue requirement.

SCE&G Cost of Service Study

Q IS SCE&G'S PROPOSED COST OF SERVICE METHODOLOGY APPROPRIATE FOR USE IN THIS PROCEEDING?

A Yes. However, it should be noted that SCE&G did not provide an electronic model of its filed cost of service study required to verify the numerous calculations incorporated within the cost of service study.

The cost study functionalizes and classifies costs in accordance with generally accepted cost of service principles. Demand related costs are allocated on demands placed on the system. Energy related costs are allocated on the quantity of energy consumed and customer related costs are allocated on the number of customers.

Q IN CONNECTION WITH YOUR ANALYSIS, DID YOU HAVE AVAILABLE TO YOU ANY COST OF SERVICE STUDIES?

A Yes, I did. I had information made available to me, which included summer coincident peak cost of service studies for the 12-month period ended December 31, 2011 that were produced and furnished by SCE&G. The most appropriate cost of service for use in this proceeding is the summer coincident peak responsibility method proposed by SCE&G consistent with past practice. This method has been consistently utilized by SCE&G and approved by this Commission since 1980 or approximately 30 years. Use of the summer coincident peak study will provide the most accurate evaluation of the cost to serve various customer classes. The use of the summer coincident peak method is also the most consistent with actual load analysis and operation of the SCE&G electric system. Cost allocation methods that directly utilize annual energy usage to allocate production investment, such as the peak and average or similar method, are completely inappropriate for use in this proceeding and should not be utilized for cost of service or serve as the basis of rate design.

Cost of Service Analysis

Q MR. PHILLIPS, PLEASE DESCRIBE SCHEDULE 1 OF EXHIBIT NP-1.

A Schedule 1 shows the load factors for the SCE&G rate classes, based on their summer coincident peak demand for this test period. The load factor for the large general service class of 83% is substantially higher than the load factors for the other major classes of customers. The residential class load factor is 47% and the small general service class load factor is 50% for the test year ended December 31, 2011.

Q HOW DID YOU COMPUTE THE LOAD FACTORS SHOWN IN SCHEDULE 1?

A I divided the kWh generated for a customer class by the product of the coincident peak demand asserted on the system by that class and the number of hours in the test year (8,760). The following equation shows the relationship between annual load factor, energy and demand.

Load Factor = Energy/Demand x 8760

Q PLEASE EXPLAIN THE SIGNIFICANCE OF THE LOAD FACTOR.

A Load factor is an indication of the degree of utilization of the demand imposed upon the utility system by a customer (or class of customers). It relates average use of the system to the maximum use at any one time. Load factor is an important indicator of the cost of serving a customer class, since fixed costs, including capital expenditures, return, depreciation, and certain taxes and expenses, are determined by the magnitude of demands imposed upon the system, and do not vary with the number of kWh produced or consumed. Stated in another manner, the fixed costs would still exist if sales were to decline. As load factor increases, the fixed costs related to the maximum demands imposed upon the system are spread over a larger number of kWh, resulting in lower per unit power costs. Similarly, as load factor decreases, higher per unit costs result.

Q DOES THE VOLTAGE LEVEL OF SERVICE AFFECT COST OF SERVICE?

A Yes. Sales by voltage level of service for each rate class are shown on Exhibit NP-1, Schedule 2. Service at higher voltage levels generally results in lower cost of providing service. The residential and street lighting classes purchase all of their power at the distribution voltage level. Since no power is supplied to the residential and street lighting classes directly from the high voltage levels, it is necessary for the Company to make investments in both primary and secondary distribution lines, as well as transmission lines and facilities, to provide service to these customer classes.

For large general service customers, approximately half of sales occur at the transmission voltage level or sub-transmission voltage level. Therefore, in supplying energy to a large portion of these large general customers, it is unnecessary for the SCE&G to make any investments or related expenditures in secondary or primary voltage distribution facilities. Since SCE&G is generally not required to incur costs below the transmission and sub-transmission voltage levels to serve many of these large general service customers, the cost per kWh of serving them is lower than the cost of serving those customers who require the lower voltage distribution system. In addition, energy losses are inversely related to voltage level of service resulting in less fuel per kWh required to serve higher voltage level large general service customers.

Q MR. PHILLIPS, HAVE YOU ANALYZED DATA TO CONSIDER THE ECONOMIES OF SCALE ASSOCIATED WITH SCE&G'S CUSTOMER-RELATED COSTS?

A Yes. Exhibit NP-1, Schedule 3 shows the average kWh sales per customer for SCE&G's major classes of service for the 12 months ended December 31, 2011. As can be seen in Schedule 3, large general service customers as a class purchased substantially more power per customer service than any of the other classes. For example, the average large general service customer used more than 1,500 times as many kWh as did the average residential customer.

These large differences in average kWh sales per customer for the various customer classes result in economies of scale in customer-related costs, such as meter reading, billing, and customer accounting expense, producing much lower customer-related costs per kWh sold to these large general service customers.

Q HAVE YOU CONSIDERED THE RELATIONSHIP BETWEEN INVESTMENT IN PLANT AND KWH SALES FOR SCE&G'S CUSTOMER CLASSES?

A Yes. Exhibit NP-1, Schedule 4 shows SCE&G's proposed rate base as SCE&G allocated it to the customer classes in its coincident peak cost of service study, expressed on a per kWh basis. As shown in Schedule 4, much less investment is required on a per kWh basis to serve the large general service customers than to serve any other class of customers.

Q HAVE YOU ALSO CONSIDERED THE RELATIONSHIP BETWEEN OPERATING EXPENSES AND KWH SALES FOR SCE&G'S CUSTOMER CLASSES?

A Yes. Exhibit NP-1, Schedule 5 shows operating expenses as SCE&G allocated them to the customer classes in its coincident peak cost of service study, expressed on a per kWh basis. Schedule 5 shows that significantly lower operating expenses are incurred per kWh sold to large general service customers than are incurred per kWh sold to residential or commercial customers.

Q PLEASE SUMMARIZE THE DATA SHOWN IN SCHEDULES 1 THROUGH 5 OF EXHIBIT NP-1.

A These schedules demonstrate how, on a per kWh basis, the costs of serving the large general service customers are much lower than the costs of serving smaller customers. Cost-based utility rates should reflect these differences.

Q MR. PHILLIPS, ARE RATES THAT REFLECT THE LOWER COSTS PER KWH OF ENERGY SOLD TO LARGE GENERAL SERVICE CUSTOMERS CONSISTENT WITH THE CONCEPT OF EQUITABLE RATES TO ALL ELECTRIC CUSTOMERS?

A Yes, absolutely. As demonstrated in Schedules 1 through 5 of Exhibit NP-1, SCE&G's costs to produce and deliver a kWh to a large general service customer are substantially less than its costs to produce and deliver a kWh to smaller users, such as a residential or a small general service customer. Equitable rates between customer classes are not determined by looking at the price paid per kWh. They are determined by evaluating whether the rates paid reasonably reflect the costs incurred by the utility. This determination is made by analyzing, in a cost of service study, whether each customer class is providing the utility with a rate of return substantially equal to the system average rate of return. If each class is providing essentially equal rates of return, then the rates are equitable among customer classes.

Analysis of Electric Load Characteristics

Q HAVE YOU REVIEWED CERTAIN PERTINENT LOAD CHARACTERISTICS OF SCE&G'S ELECTRIC SYSTEM?

A Yes. I have reviewed SCE&G's load characteristics for the test year and I am generally familiar with the load characteristics of the SCE&G electric system.

SCE&G typically has a dominant summer coincident peak that occurs in the afternoon on a weekday in July or August. SCE&G's retail system load factor was 58.52% for the test year based on the peak day four-hour band methodology as utilized by the Company for many years as shown on Schedule 1 of Exhibit NP-1. An electric system load factor in this range is generally characteristic of a utility with a dominant annual system peak.

Q HAVE YOU HAD AN OPPORTUNITY TO REVIEW FORECAST PEAK LOAD DATA?

A Yes. Schedule 6 of Exhibit NP-1 is an analysis of SCE&G's load forecast and load pattern as outlined in the 2012 Integrated Resource Plan as filed in Docket No. 2012-9-E. The Company projects dominant and increasing summer peak demands over the entire 15 year planning horizon. The load factor continues to decline and is projected to decrease to 53.3% by 2026. This data shows a clear and continued dominance of the summer peak. It is important to recognize that SCE&G uses its annual summer planning peak to calculate its system reserve margin, which is a main indictor of a utility's capacity requirement. As reserve margins decrease, additional capacity is required to serve the system load in a reliable manner. Capacity is basically the rated capability of a generating station or transmission line. As reserve margins decrease, additional capacity is required to maintain reliable service. New generating and transmission capacity requires long lead times and generally increases costs to ratepayers.

Q HOW DOES THIS FORECAST PEAK LOAD DATA RELATE TO THE APPROPRIATE COST OF SERVICE METHODOLOGY?

A A method of cost allocation which allocates some portion of fixed production cost on annual energy usage, such as the "peak and average" method (or other energy-based methods), would not adequately account for the dominant summer coincident peak and therefore fail to reflect the actual load characteristics of the SCE&G system. Allocating production investment on average demand or kWh signals customers that a demand created at a peak hour is the same as a demand created during an off-peak hour and is in conflict with SCE&G's demand management goals. The average of the 12 coincident peak method is also not appropriate for cost allocation since SCE&G's monthly peaks are neither equal in importance nor indicative of cost causation. The 12 coincident peak method and the peak and average method (which also relies on off-peak periods and on annual energy consumption) are at odds with SCE&G's present and proposed rates that charge customers substantially more for demands created during the summer months.

As previously stated, SCE&G data indicates that its capacity expansion planning is based on forecasted summer peak loads. As summer peak demands increase, reserve margins decrease which translates into the need for additional capacity. SCE&G is basically adding generation capacity to meet its forecasted summer peak demands. Therefore, I recommend that the Commission adopt the summer coincident peak method of cost allocation consistent with past practice.

Allocation of Production Investment

Q IN YOUR OPINION, IS IT APPROPRIATE TO CLASSIFY ALL PRODUCTION INVESTMENT AS DEMAND-RELATED?

A Yes. Consumers take for granted that when they flip the switch, an electric light or appliance will turn on and run. Since electric energy cannot be stored in large quantities for any significant length of time, utilities must provide adequate generating capacity to meet the demands of their customers when those customers decide to make those demands. Therefore, investment in generation plant is properly classified as a demand-related cost.

Q WHAT ABOUT THE ARGUMENT THAT SOME PORTION OF THE INVESTMENT IN BASE LOAD PLANT SHOULD BE CLASSIFIED AS ENERGY-RELATED, BASED ON THE THEORY THAT A UTILITY IS WILLING TO MAKE CERTAIN ADDITIONAL CAPITAL INVESTMENTS TO REDUCE ITS LEVEL OF FUEL COSTS?

A With respect to this argument, it should be noted that the economic choice between a base load plant and a peaking plant must consider both capital costs and operating costs, and therefore is a function of average total costs. The capital cost of peaking plants is lower than the capital cost of base load plants, but the operating costs of peaking plants are higher than the operating costs of base load plants. Moreover, when the hours of use are considered, the fixed cost per kWh for base load plant is usually less than the fixed cost per kWh for the peaking plant. Of course, since the fuel costs of base load plants are lower than the fuel costs of peaking plants, the overall cost per kWh for base load plants is also less than the overall cost per kWh for peaking plants.

It is necessary, therefore, to look at both capital costs and operating costs in light of the expected capacity factor of the plant. The fact that base load plants have lower fuel costs than peaking plants does not mean that the investment in base load plants is strictly to achieve lower fuel costs. Investment in a base load plant would be made to achieve lower total costs, of which fixed costs and fuel costs are the primary ingredients.

For any given system, the capital costs are not a function of the number of kWh generated, but are fixed and therefore are properly related to system demands, not to kWh sold. These costs are fixed in that the necessity of earning a return on the investment, recovering the capital cost (depreciation), and operating the property are related to the existence of the property and not to the number of kWh sold. If sales volumes change, these costs are not affected, but continue to be incurred, making them fixed or demand-related in nature.

It is not proper to classify a portion of the fixed costs related to production based on energy. However, if an attempt were made to increase the allocation of investment to one group of customers, on the theory that those customers benefit more than others from the lower energy costs that result from the operation of a base load plant as opposed to a peaking plant, the analysis should be carried to its logical conclusion. The logical conclusion would be to fairly and symmetrically allocate energy costs to the group of customers who are forced to bear the higher capital costs allocated to them on a kWh basis. Energy costs allocated to the high load factor class should recognize lower operating costs which result from the higher capital costs of the base load plants. Unfortunately, in the past, when the peak and average method was proposed, the lower fuel costs were not properly assigned to the industrial class of customers.

Q BASED ON THIS ANALYSIS, DO YOU BELIEVE THAT IT IS APPROPRIATE TO ALLOCATE PRODUCTION OR TRANSMISSION INVESTMENT COSTS ON A METHOD THAT IS SUBSTANTIALLY A KWH ALLOCATION, SUCH AS THE PEAK AND AVERAGE METHOD?

A No. These kWh types of allocation methods are totally inappropriate. They give far too much weight to energy consumption, and understate the importance of peak loads that are dominant on the SCE&G electric system.

Q ARE THERE ANY OTHER REASONS WHY YOU DISAGREE WITH THE CLASSIFICATION OF FIXED COSTS PARTLY ON THE BASIS OF ENERGY?

A Yes. Since rate design should be based on cost of service, significant rate design problems will result from the allocation of fixed costs on an energy basis. First, allocation of fixed costs partly based on energy consumption makes the rates less stable than they would otherwise be, and second, allocation of fixed costs partly based on energy reduces the incentive given to customers by off-peak pricing provisions. Allocating production investment on an energy basis signals customers that a demand created at the peak hour is the same as a demand created during the off-peak hour. Customers that shift loads in response to time-of-day rates will not be treated fairly by a kWh type of costing methodology, such as the peak and average method.

Q PLEASE EXPLAIN.

A With respect to stability, if a significant proportion of fixed costs is classified on the basis of energy and the level of kWh sales decreases (as often happens during an economic downturn), the utility's revenues will drop more than its costs, since fixed costs are being collected in the energy or variable portion of the rate. On the other hand, a proper recognition of the differentiation between demand and energy costs would, under these circumstances, cause revenues to decline in closer correspondence to the decline in costs, since the energy charges would basically recover those costs which do, in fact, vary with the number of kWh sold.

With respect to the concept of off-peak pricing, classification of a portion of the demand-related costs based on energy reduces the savings to the customer due to increased use during off-peak hours. For example, if a customer were to increase his consumption during off-peak hours (without changing his demands or energy consumption during the on-peak hours), this classification method would allocate more investment in fixed costs to the customer than before, since the number of kWh added during the off-peak period would increase the allocation of fixed costs, even though the system's total capacity and capacity-related costs had not increased. This reduces the savings that would be available to the customer as a result of adding load off-peak as opposed to on-peak. This inequity is compounded when viewed by a customer who shifts summer loads to the remaining eight months of the year. The customer would receive lower rates, temporarily, but would not receive an appropriate reduction in the allocation of demand-related costs. Therefore, this customer can expect an above-average increase in the next rate case as a reward for his shifting. This result is a further demonstration of the inappropriateness of an energy type (average demand) approach to the allocation of fixed costs. Allocating fixed costs on an energy basis is in direct conflict with the current and proposed rate structure and the time-of-day/seasonal load management type rates previously approved by this Commission.

Distribution of Revenue Increase Proposed by SCE&G

Q HAVE YOU REVIEWED THE MANNER IN WHICH SCE&G PROPOSES TO INCREASE THE RATES CHARGED TO ITS VARIOUS CUSTOMER CLASSES?

A Yes, I have. Schedule 1 of Exhibit NP-2 summarizes SCE&G's proposal. SCE&G proposes to increase residential revenues by 7.4%, small general service revenues by 4.2%, medium general service by 6.0%, large general service revenues by 7.2%, and lighting class revenues by 7.4%. The distribution of the increase as presented by the Company is based on its stated goal of moving toward cost of service, with measured steps and consideration to public policy and competitive issues.

Q HAVE YOU EXAMINED THE CLASS RATES OF RETURN FOR THE TEST YEAR BASED ON SCE&G'S PROPOSED DISTRIBUTION OF THE REVENUE INCREASE?

A Yes. Schedule 2 of Exhibit NP-2 shows rates of return and indexes, for each class of service under present and SCE&G proposed rates utilizing the summer coincident peak method of cost allocation.

Q DO YOU HAVE CONCERNS REGARDING SCE&G'S PROPOSAL?

A Yes. The loads, sales levels and revenues used in the cost of service study cannot be considered normal. This is a particular concern with respect to the large general service class. The economy has not fully recovered and the manufacturing segment is vulnerable to actions both within the U.S. and globally. Therefore, higher than average electric rate increase to the LGS class may prove harmful to the entire service territory.

Q DOESN'T THE PROPOSED FUEL DECREASE HELP THE SITUATION?

A The fuel decrease to some extent scales back previous increases but it is not permanent and subject to change. SCE&G's application in this case clearly states:

> "35. In light of uncertainty as to fuel costs, SCE&G also requests that the Commission authorize carrying costs on any under-recovered balance in the base fuel cost recovery account after January 1, 2013, that is greater than $24,338,526 using a rate equal to the ten-year Unites States Treasury Bill plus 65 basis points." (Application pp. 9-10)

It is clear that fuel costs are uncertain and may increase in the future.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO A COST-BASED DISTRIBUTION OF ANY INCREASE AWARDED TO SCE&G IN THIS PROCEEDING?

A There is a proven method utilized for many years to increase rates in a manner that is fair and equitable and maintains existing rate relationships. SCE&G's present revenues are based on tariffs approved by the Commission. An equal percentage increase does not require the use of load data, which may not normal, to make allocations. The present revenues set forth by SCE&G in this proceeding include both fuel and non-fuel revenues. Fuel revenues and fuel costs are separate and apart from the other portion of the rates. Fuel costs are increased (or decreased) in separate annual proceedings before this Commission. The $151.5 million increase requested by SCE&G in this proceeding is for costs other than the cost of fuel. To maintain current rate relationships, any increase allowed in this proceeding should be distributed to classes by increasing non-fuel revenues on an equal percentage or an across-the-board basis.

For a base rate increase, such as requested in this proceeding, existing rate relationships can be exactly preserved by increasing non-fuel rates by an equal percentage basis. The results of an equal percentage increase to classes on a non-fuel basis are shown on Exhibit NP-2, Schedule 3. The increases to the residential and large general service classes are moderated compared to SCE&G's proposal.

Q CAN YOU PROVIDE AN ILLUSTRATION OF THE USE OF THE EQUAL PERCENTAGE OF NON-FUEL REVENUES TO INCREASE RATES TO THE CUSTOMER CLASSES?

A Yes. I will provide an older example and a current example. This method was proposed by Georgia Power Company and approved by the Georgia Public Service Commission in the early 1980s.

"<u>INTERCLASS ALLOCATION</u>

> Having found the rate award, the Commission must decide what proportion of the rate award should be borne by the respective classes of the Company's customers. The Company has the following classes of customers: residential, industrial, commercial and street and highway lighting. The Company's position was that the required increase in retail revenues should be allocated to each of the retail customer classes in proportion to each class' revenues, exclusive of fuel cost recovery revenues. This method of spreading the increase has two advantages. First, the rate increase is based on those costs of service which are not recovered by the fuel cost recovery mechanism, and, therefore, the increase in class revenue requirements should not be based on fuel cost recovery revenues.

> Second, this allocation procedure preserves the traditional relationship between class rates of return, with the industrial class at the system average, the commercial class above average, and the residential class below average. By maintaining this relationship, the Commission will foster rate continuity, while assuring that the State of Georgia is not placed at an artificial competitive disadvantage in attracting new industry, or that industry located here does not have artificially high energy costs vis-à-vis those energy costs of industries located in other states and that the commercial class is not harmed relative to its competition which is almost exclusively within the State of Georgia.
>
> Having heard all the arguments and considering all the evidence, the Commission finds the Company's arguments most persuasive. The Commission must consider the best interest of all classes of customers. The Company's position on this matter comports with the Commission's previous decisions, maintains continuity, takes into consideration the ability to pay of each class of customer, does not impact adversely on any class with respect to its respective competition and is logically consistent with a ratemaking proceeding not directly involving fuel costs. Therefore, the Commission finds as a matter of fact that the allowed rate increase should be allocated to the separate classes uniformly and equally on base revenue exclusive of fuel." (Interclass Allocation, pages 21 and 22, Docket No. 3270-U, File No. 19314.)

A more recent example is the current Virginia base rate filing by Virginia Electric and Power Company ("VEPCO"), which operates in North Carolina as Dominion North Carolina Power. In that matter PUE-2009-00019, VEPCO witness, David Koogler, proposed to allocate the base rate increase on the basis of an equal percentage of non-fuel revenues for each rate classes.

Q HAVE YOU EXAMINED THE CLASS RATES OF RETURN BASED ON YOUR RECOMMENDED METHOD OF DISTRIBUTING ANY INCREASE TO CLASSES OF SERVICE?

A Yes. Schedule 4 of Exhibit NP-2 shows rates of return and indexes under this approach. All classes (except residential which virtually stays the same) move closer to cost in a more measured manner than the Company's approach.

Rate Design

Q HAVE YOU REVIEWED THE MANNER IN WHICH SCE&G PROPOSES TO ADJUST ITS VARIOUS INDUSTRIAL RATE SCHEDULES?

A Schedule 5 of Exhibit NP-2 shows the rate design and rate increase by component as proposed by SCE&G for Rate 23, Industrial Power Service. As presented by SCG&E, the demand component of the rate is being increased by approximately 7.3% and the energy component of the rate is being increased by 4.8%. Schedule 6 of Exhibit NP-2 is a similar analysis for Rate 24, large general service time-of-use. The demand component of the rate has increased by approximately 7.2% and the energy rate has increased by about 4.3%.

SCE&G proposes to place the majority of the increase in the demand component of the rate, which is appropriate. Increasing the demand charge is consistent with cost of service. Fuel cost changes are the subject of fuel adjustment proceedings and rate changes associated with changes in fuel costs are the subject of separate proceedings. The proposed rate design levels should, of course, be reduced to reflect my recommended distribution of the increase and also to reflect the extent that SCE&G's overall requested increase is reduced by the Commission.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Nicholas Phillips, Jr.

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from Lawrence Institute of Technology in 1968 with a Bachelor of Science Degree in Electrical Engineering. I received a Master's of Business Administration Degree from Wayne State University in 1972. Since that time I have taken many Masters and Ph.D. level courses in the field of Economics at Wayne State University and the University of Missouri.

I was employed by The Detroit Edison Company in June of 1968 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included the overhead and underground design, construction, operation and specifications for transmission and distribution equipment; budgeting and cost control for operations and capital expenditures; equipment performance under field and laboratory conditions; and emergency service restoration. I also worked in various districts, planning system expansion and construction based on increased and changing loads.

Since 1973, I have been engaged in the preparation of studies involving revenue requirements based on the cost to serve electric, steam, water and other portions of utility operations.

Other responsibilities have included power plant studies; profitability of various segments of utility operations; administration and recovery of fuel and purchased power costs; sale of utility plant; rate investigations; depreciation accrual rates; economic investigations; the determination of rate base, operating income, rate of return; contract analysis; rate design and revenue requirements in general.

I have held various positions including Supervisor of Cost of Service, Supervisor of Economic studies and Depreciation, Assistant Director of Load Research, and was designated as Manager of various rate cases before the Michigan Public Service Commission and the Federal Energy Regulatory Commission. I was acting as Director of Revenue Requirements when I left Detroit Edison to accept a position at Drazen-Brubaker & Associates, Inc., in May of 1979.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and has assumed the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff.

Our firm has prepared many studies involving original cost and annual depreciation accrual rates relating to electric, steam, gas and water properties, as well as cost of service studies in connection with rate cases and negotiation of contracts for substantial quantities of gas and electricity for industrial use. In these cases, it was necessary to analyze property records, depreciation accrual rates and reserves, rate base determinations, operating revenues, operating expenses, cost of capital and all other elements relating to cost of service.

In general, we are engaged in valuation and depreciation studies, rate work, feasibility, economic and cost of service studies and the design of rates for utility services. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q WHAT ADDITIONAL EDUCATIONAL, PROFESSIONAL EXPERIENCE AND AFFILIATIONS HAVE YOU HAD?

A I have completed various courses and attended many seminars concerned with rate design, load research, capital recovery, depreciation, and financial evaluation. I have served as an instructor of mathematics of finance at the Detroit College of Business located in Dearborn, Michigan. I have also lectured on rate and revenue requirement topics.

Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

A Yes. I have appeared before the New Jersey Board of Public Utilities, the Public Service Commissions of Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Montana, New York, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Virginia, West Virginia, and Wisconsin, the Lansing Board of Water and Light, the District of Columbia, and the Council of the City of New Orleans in numerous proceedings concerning cost of service, rate base, unit costs, pro forma operating income, appropriate class rates of return, adjustments to the income statement, revenue requirements, rate design, integrated resource planning, power plant operations, fuel cost recovery, regulatory issues, rate-making issues, environmental compliance, avoided costs, cogeneration, cost recovery, economic dispatch, rate of return, demand-side management, regulatory accounting and various other items.

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Exhibit NP-1
Schedule 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Major Class Load Factors
for the Year Ended December 31, 2011

Line	Rate Class	Energy Requirement (MWh)	Demand at System Peak (MW)	Load Factor Based on Four-Hour Average Coincident Demand on System Peak Day
		(1)	(2)	(3)
1	Residential	8,611,997	2,085	47.15%
2	Small General Service	3,473,254	794	49.93%
3	Medium General Service	2,522,903	453	63.56%
4	Large General Service	7,394,357	1,017	82.98%
5	Street Lighting	294,416	-	N/M
6	Total Retail	22,296,928	4,349	58.52%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Major Class Sales by Voltage Level
for the Year Ended December 31, 2011

Line	Rate Class	Total Retail (1)	Secondary (2)	Primary (3)	Subtrans-mission (4)	Trans-mission (5)
1	Residential	100.0%	100.0%	0.0%	0.0%	0.0%
2	Small General Service	100.0%	99.8%	0.1%	0.1%	0.0%
3	Medium General Service	100.0%	85.0%	14.9%	0.1%	0.0%
4	Large General Service	100.0%	0.0%	52.7%	4.5%	42.8%
5	Street Lighting	100.0%	100.0%	0.0%	0.0%	0.0%
6	Total Retail	100.0%	62.2%	20.7%	1.6%	15.5%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Megawatthour Sales, Number of Customers and Kilowatthour Sales per Customer for the Year Ended December 31, 2011

Line	Rate Class	Energy Sales (MWh) (1)	Number of Customers (2)	Kilowatthour Sales per Customer (3)
1	Residential	8,262,640	570,382	14,486
2	Small General Service	3,332,465	91,162	36,555
3	Medium General Service	2,424,513	2,802	865,279
4	Large General Service	7,235,163	315	22,968,771
5	Street Lighting	282,472	240,077	1,177
6	Total Retail	21,537,253	904,738	23,805

Exhibit NP-1
Schedule 4

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Rate Base Expressed
on a per Kilowatthour Sold Basis
for the Year Ended December 31, 2011

Line	Rate Class	Rate Base (000) (1)	Energy Sales (MWh) (2)	Rate Base Expressed on a per kWh Basis (3)
1	Residential	$ 2,449,231	8,262,640	29.64 ¢
2	Small General Service	866,443	3,332,465	26.00
3	Medium General Service	458,452	2,424,513	18.91
4	Large General Service	936,614	7,235,163	12.95
5	Street Lighting	158,397	282,472	56.08
6	Total Retail	$ 4,869,137	21,537,253	22.61 ¢

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Operating Expenses Expressed on a per Kilowatthour Sold Basis for the Year Ended December 31, 2011

Line	Rate Class	Operating Expenses (000)	Energy Sales (MWh)	Expenses Expressed on a per kWh Basis
		(1)	(2)	(3)
1	Residential	$ 863,067	8,262,640	10.45 ¢
2	Small General Service	323,887	3,332,465	9.72
3	Medium General Service	198,877	2,424,513	8.20
4	Large General Service	482,608	7,235,163	6.67
5	Street Lighting	43,575	282,472	15.43
6	Total Retail	$ 1,912,014	21,537,253	8.88 ¢

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Load Forecast
for the Years 2012 through 2026

Line	Year	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWh)	Load Factor
		(1)	(2)	(3)	(4)
1	2012	4,750	4,660	22,896	54.9%
2	2013	4,772	4,703	22,963	54.9%
3	2014	4,852	4,732	23,182	54.5%
4	2015	4,929	4,782	23,378	54.1%
5	2016	5,035	4,870	23,740	53.7%
6	2017	5,119	4,960	24,095	53.7%
7	2018	5,176	5,039	24,393	53.8%
8	2019	5,239	5,110	24,695	53.8%
9	2020	5,313	5,175	24,937	53.4%
10	2021	5,368	5,235	25,157	53.5%
11	2022	5,447	5,305	25,517	53.5%
12	2023	5,529	5,381	25,875	53.4%
13	2024	5,612	5,455	26,243	53.2%
14	2025	5,691	5,528	26,607	53.4%
15	2026	5,768	5,598	26,937	53.3%

Exhibit NP-2
Schedule 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Summary of SCE&G Proposed Rate Increase by Customer Classes

Line	Rate Class	Current Revenue (000)	SCE&G Proposed Revenue (000)	SCE&G Proposed Increase Amount (000)	SCE&G Proposed Increase Percent
		(1)	(2)	(3)	(4)
1	Residential	$ 1,010,583	$ 1,084,895	$ 74,312	7.35%
2	Small General Service	405,603	422,603	17,000	4.19%
3	Medium General Service	240,243	254,643	14,400	5.99%
4	Large General Service	580,716	622,326	41,610	7.17%
5	Street Lighting	56,434	60,614	4,180	7.41%
6	Total Retail	$ 2,293,580	$ 2,445,081	$ 151,501	6.61%

Exhibit NP-2
Schedule 2

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Rates of Return and Indexes
at Present and Company Proposed Rates
12 Months Ended December 31, 2011

Line	Rate Class	Present Rates Rate of Return (1)	Present Rates Index (2)	Proposed Rates Rate of Return (3)	Proposed Rates Index (4)
1	Residential	6.29%	95	8.16%	95
2	Small General Service	8.60%	129	9.81%	115
3	Medium General Service	7.43%	112	9.36%	109
4	Large General Service	5.19%	78	7.92%	93
5	Street Lighting	7.79%	117	9.41%	110
6	Total Retail	6.64%	100	8.56%	100

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Recommended Increase Based on Equal Percent of Non-Fuel Revenue

Line	Rate Class	Current Revenue (000)	Non-Fuel Revenue (000)	Equal Percent Non-Fuel Revenue Distribution Amount (000)	Equal Percent Non-Fuel Revenue Distribution Percent	Equal Percent Increase as a Percent of Approved Revenue
		(1)	(2)	(3)	(4)	(5)
1	Residential	$ 1,010,583	$ 710,319	$ 71,005	10.00%	7.03%
2	Small General Service	405,603	284,701	28,459	10.00%	7.02%
3	Medium General Service	240,243	152,719	15,266	10.00%	6.35%
4	Large General Service	580,716	321,408	32,129	10.00%	5.53%
5	Street Lighting	56,434	46,432	4,641	10.00%	8.22%
6	Total Retail	$ 2,293,580	$ 1,515,578	$ 151,501	10.00%	6.61%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Rates of Return and Indexes
at Present and Recommended Rates
12 Months Ended December 31, 2011

		Present Rates		Recommended Rates	
Line	Rate Class	Rate of Return (1)	Index (2)	Rate of Return (3)	Index (4)
1	Residential	6.29%	95	8.07%	94
2	Small General Service	8.60%	129	10.62%	124
3	Medium General Service	7.43%	112	9.48%	111
4	Large General Service	5.19%	78	7.30%	85
5	Street Lighting	7.79%	117	9.59%	112
6	Total Retail	6.64%	100	8.56%	100

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Comparision of Present and Proposed Demand and Energy Components for Rate 23, Industrial Power Service

Line	Description	Present Rate (1)	SCE&G Proposed Rate (2)	SCE&G Proposed Increase Amount (3)	SCE&G Proposed Increase Percent (4)
	Basic Facilities Charge:				
1	Per Month	$ 1,800	$ 1,900	$ 100	5.56%
	Demand Charge:				
2	All kW	$ 13.88	$ 14.90	$ 1.02	7.35%
	Energy Charge:				
3	All kWh	$ 0.04757	$ 0.04987	$ 0.00230	4.83%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2012-218-E

Comparision of Present and Proposed Demand and Energy Components for Rate 24, Large General Service Time-of-Use

Line	Description	Present Rate (1)	SCE&G Proposed Rate (2)	SCE&G Proposed Increase Amount (3)	SCE&G Proposed Increase Percent (4)
	Basic Facilities Charge:				
1	Per Month	$ 1,800	$ 1,900	$ 100	5.56%
	Demand Charge:				
	On-Peak Billing Demand kW				
2	Summer (Jun-Sep)	$ 16.78	$ 18.01	$ 1.23	7.33%
3	Non-Summer (Oct-May)	$ 11.77	$ 12.61	$ 0.84	7.14%
4	Off-Peak Billing Demand kW	$ 5.12	$ 5.42	$ 0.30	5.86%
	Energy Charge:				
	On-Peak kWh				
5	Summer (Jun-Sep)	$ 0.07911	$ 0.08244	$ 0.00333	4.21%
6	Non-Summer (Oct-May)	$ 0.05712	$ 0.05962	$ 0.00250	4.38%
7	Off-Peak kWh	$ 0.04364	$ 0.04585	$ 0.00221	5.06%